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BEFORE THE ARIZONA CORPORATION COMMISSION
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COMMISSIONERS

DOUG LITTLE - CHAIRMAN
BOB STUMP
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TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF
TUCSON ELECTRIC POWER COMPANY FOR
APPROVAL OF ITS 2016 RENEWABLE
ENERGY STANDARD IMPLEMENTATION
PLAN.

DOCKET NO. E-01933A-15-0239

IN THE MATTER OF THE APPLICATION OF
TUCSON ELECTRIC POWER COMPANY FOR
THE ESTABLISHMENT OF JUST AND
REASONABLE RATES AND CHARGES
DESIGNED TO REALIZE A REASONABLE
RATE OF RETURN ON THE FAIR VALUE OF
THE PROPERTIES OF TUCSON ELECTRIC
POWER COMPANY DEVOTED TO ITS
OPERATIONS THROUGHOUT THE STATE OF
ARIZONA AND FOR RELATED APPROVALS.

DOCKET NO. E-01933A-15-0322

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REPLY BRIEF

OF TUCSON ELECTRIC POWER COMPANY

NOVEMBER 14, 2016

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1 **I. Introduction.**

2 The opening briefs present a stark dichotomy between the broad support of the revenue
3 requirement settlement and parties supporting positions that would further broaden under
4 recovery of costs. The revenue requirement settlement is supported by a wide range of interests,
5 and the revenue requirement demonstrates that Tucson Electric Power Company's ("TEP" or
6 "Company") is not currently collecting sufficient revenues. There is also general
7 acknowledgement that TEP is recovering approximately 89% of fixed costs from certain rate
8 classes through volumetric rates. Moreover, there is a general recognition that the Commission's
9 renewable and energy efficiency mandates are causing reduced kWh sales. However, rather than
10 supporting modifications to rate design and the Lost Fixed Cost Recovery ("LFCR") mechanism
11 that would mitigate – but not eliminate – these challenges, many of the parties are taking
12 positions that would exacerbate them. Their positions would lead to increasingly inequitable
13 recovery of fixed costs from TEP ratepayers and effectively preclude any opportunity for TEP to
14 earn its authorized rate of return.

15 TEP's objectives in filing this rate case are approval of a just and reasonable revenue
16 requirement, and approval of an appropriate rate design that provides the Company a reasonable
17 opportunity to collect its revenue requirement. Although there is broad and diverse support with
18 respect to revenue requirement, much dispute remains about rate design. The Company has
19 demonstrated throughout this proceeding that its proposals, taken as a whole, are balanced and
20 are fair to all its customers - not just select customer groups or special interests. In doing so, the
21 Company has been flexible in its approach and willing to put forth various options.

22 This Reply Brief primarily rebuts various positions taken by other parties, and also re-
23 emphasizes key points that the Company believes are important for the Commission to consider.
24 However, the Company is not addressing every point or argument included in its Initial Brief;
25 and the Company relies on its Initial Brief for all points not modified or conceded in this Reply
26 Brief.

1 **II. The Commission should approve the revenue requirement settlement.**

2 The Settlement Agreement on revenue requirement is fair and reasonable, is supported by
3 a broad coalition of parties with diverse interests, was negotiated in an open and transparent
4 process, and is in the public interest. Based on initial briefing, there appear to be only three
5 issues that potentially impact the revenue requirement: (i) DOD's position on the rate of return;
6 (ii) SWEEP's request to include a significant portion of the cost of energy efficiency programs in
7 base rates; and (iii) EFCA's request to exclude approximately \$16,000 related to a TORS system
8 from TEP's \$2.8 billion fair value rate base. None of these concerns warrant rejection of the
9 broadly supported Settlement Agreement.

10 **A. The DOD's Rate of Return should be rejected.**

11 The Settlement Agreement includes fair and reasonable terms, including a return on
12 common equity ("ROE") of 9.75% and an embedded cost of long-term debt of 4.32% (resulting
13 in a weighted average cost of capital of 7.04%).¹ The only party in this proceeding that disagrees
14 with the ROE established by the Settlement Agreement is the DOD. Despite the range
15 recommended by its witness, which extends to 9.70%, and the analysis presented by its witness,
16 which supports a value as high as 9.80%, DOD asserts that the ROE of 9.75% is unreasonable.

17 **1. *Recently Authorized ROEs support the Settlement Agreement's ROE.***

18 DOD suggests that "this case contains irrefutable market evidence that the current cost of
19 equity for electric utilities is no higher than 9.5%".² Yet, the DOD further observes that
20 "authorized ROEs for electric utilities have ranged from 9.58% to 9.80%".³ Based on this data,
21 DOD is suggesting that the ROE for TEP should be below the average of recently authorized
22 ROEs. There is no evidence in this case that demonstrates that TEP has lower risk and therefore
23 should be authorized an ROE that is lower than the average authorized ROE for other vertically
24 integrated electric utilities. Furthermore, Chart 1 of Ms. Bulkley's Rebuttal Testimony provides
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¹ Ex. TEP-3 (Settlement Agreement) §3.2.

27 ² DOD Brief at 2:17-18.

³ DOD Brief at 3:9.

1 more insight into the authorized ROEs that are included in the 2015 and 2016 averages.⁴ As
2 shown in that chart, the absolute range of authorized ROE's for electric utilities was from 9.30%
3 to 10.30%. The ROE in the Settlement Agreement of 9.75% is well within the range of recently
4 authorized ROEs and therefore represents a reasonable compromise between the Parties.

5 **2. DOD's recommendation is inconsistent with the analysis and testimony**
6 **presented by DOD's witness, Mr. Gorman.**

7 Although DOD's brief asserts that the evidence demonstrates that the return for TEP
8 should be no higher than 9.50%, the evidentiary record, including testimony from DOD's cost of
9 capital expert, Mr. Gorman, presents several analyses that undermine DOD's assertions.

- 10 ○ Based on the results of his analyses, Mr. Gorman establishes a recommended range
11 of ROEs from 8.90% to 9.70%, which exceeds the threshold established by DOD.⁵
- 12 ○ Mr. Gorman reports that the range of authorized ROEs for integrated electric
13 utility companies was from 9.30% to 10.30%, with an average of 9.70%.⁶
- 14 ○ Mr. Gorman refines that range to include only the authorized ROEs in litigated
15 cases. That range was between 9.66% and 9.72% with a midpoint of 9.69%. Mr.
16 Gorman further notes that this "is generally consistent with the high end of my
17 recommended range of 8.9% to 9.7%".⁷
- 18 ○ Ex. MPG-24 to Mr. Gorman's Rebuttal Testimony demonstrates that the average
19 authorized ROEs for vertically integrated electric utilities in settled and litigated
20 cases have been in the range of 9.63% to 9.78% over the period from 2015-2016.⁸

21 Based on Mr. Gorman's own analysis, the authorized ROEs for vertically integrated
22 electric utilities have been as high as 10.30%, but the average authorized ROE for vertically
23 integrated electric companies has been in the range of 9.66% to 9.78%, considering settled and
24 litigated cases. Therefore, the data does not demonstrate that the ROE ought not exceed 9.50% as

25 ⁴ Ex. TEP-11 (Bulkley Rebuttal) at 12.

26 ⁵ Ex. DOD/FEA-4 (Gorman Surrebuttal) at 4:22.

⁶ Ex. DOD/FEA-4 (Gorman Surrebuttal) at 7:6-8.

27 ⁷ Ex. DOD/FEA-4 (Gorman Surrebuttal) at 7:8-12.

⁸ Ex. DOD/FEA-4 (Gorman Surrebuttal). Ex. MPG-24.

DOD suggests. Furthermore, Mr. Gorman's own Ex. MPG-24 demonstrates that the Settlement ROE is within the range established by the "market".⁹

3. Mr. Gorman's DCF and CAPM results are significantly below recently authorized ROEs.

DOD disputes the cost of capital, suggesting that all non-Company witnesses recommended a range of ROEs between 9.20% and 9.50%.¹⁰ As support for their recommendation that the ROE should be no more than 9.50%, the DOD summarizes the assumptions and methodologies that Mr. Gorman relied on to establish his recommended ROE range.¹¹

Methodology	Low	High	Recommendation
Constant Growth DCF ¹²	7.72%	8.71%	
Multi-Stage DCF ¹³	7.89%	7.99%	
Average DCF ¹⁴	8.25%	8.10%	8.70%
CAPM ¹⁵	8.01%	9.44%	9.10% ¹⁶
Treasury Bond Risk Premium	9.60%	9.80%	9.70%

Ms. Bulkley's rebuttal and rejoinder testimony specifically address the assumptions and methodologies relied on by Mr. Gorman.¹⁷ In her Rejoinder Testimony, Ms. Bulkley addresses

⁹ Ex. DOD/FEA-4 (Gorman Surrebuttal), Ex. MPG-24.

¹⁰ DOD Brief at 2-3.

¹¹ DOD Brief at 7-19.

¹² DOD Brief at 13.

¹³ DOD Brief at 13.

¹⁴ DOD Brief at 13.

¹⁵ Ex. DOD-3 (Gorman Direct), Ex. MPG-17

¹⁶ DOD Brief at 19.

¹⁷ Ex. TEP-11 (Bulkley Rebuttal) at 55-77. Specifically, Ms. Bulkley addresses Mr. Gorman's DCF analysis in her Rebuttal Testimony at pages 58-63. Ms. Bulkley addresses the assumptions used in Mr. Gorman's CAPM analysis in her Rebuttal Testimony at pages 63-66. Finally, Ms. Bulkley responds to Mr. Gorman's Treasury Bond Risk Premium analysis on pages 66-70 of her Rebuttal Testimony.

1 Mr. Gorman's assertion that the market "is embracing returns on equity of 9.5 percent and lower
2 for electric utilities". Ms. Bulkley notes that the data Mr. Gorman relies on identifies a range from
3 9.30% to 10.35% for the 2015-2016 period, with a midpoint of 9.80% and a simple average of
4 9.73%, supporting the settlement ROE of 9.75%.¹⁸

5 While there are many technical arguments discussed between the Direct, Rebuttal,
6 Surrebuttal and Rejoinder testimonies of Ms. Bulkley and Mr. Gorman, a comparison of the
7 returns that resulted from Mr. Gorman's ROE estimation models with the authorized ROEs
8 demonstrates that Mr. Gorman's DCF and CAPM analyses are unreasonably low and are not
9 reflective of the cost of capital for a vertically integrated electric utility with a large amount of
10 coal-fired generation in its resource portfolio. Mr. Gorman states that the lower end of his range
11 of results, 8.90%, is established based on his DCF and CAPM analyses. As shown in the table
12 above, the ROE results that Mr. Gorman develops using the DCF methodology range from 7.72%
13 to 8.71%. Mr. Gorman's CAPM results range from 8.01% to 9.44%.

14 Over the period from 2013 through 2016, there has not been a single authorized ROE that
15 is within the range established by Mr. Gorman's DCF results.¹⁹ Mr. Gorman's CAPM
16 recommendation of 9.10% is 53 basis points below the low end of the range of recently authorized
17 ROEs for vertically integrated electric utilities.²⁰ The only methodology that Mr. Gorman
18 develops that is within the range of recently authorized ROEs is his Treasury Bond Yield Risk
19 Premium approach, which estimates the ROE between 9.60% and 9.80%. The Settlement ROE of
20 9.75% falls within the range established by that methodology. Therefore, the results of the
21 majority of Mr. Gorman's analyses are not reasonable when compared with the range of
22 authorized ROEs presented in his Surrebuttal Testimony.

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26 ¹⁸ Ex. TEP-12 (Bulkley Rejoinder) at 4.

27 ¹⁹ Ex. TEP-11 (Bulkley Rebuttal), Chart 1 at p. 12.

²⁰ Ex. DOD/FEA-4 (Gorman Surrebuttal), Ex. MPG-24.

1 **4. DOD's critique of Ms. Bulkley's analysis is unfounded.**

2 The DOD's Brief includes approximately 8 pages summarizing Mr. Gorman's critiques
3 and criticisms of Ms. Bulkley's application of the ROE estimation models, the assumptions used
4 in those models, Ms. Bulkley's initial recommendation of 10.30% and the Company's revised
5 request for an ROE of 10.00%. Ms. Bulkley's responses to Mr. Gorman in her Rebuttal and
6 Rejoinder Testimonies demonstrate that the methodologies and assumptions that she relied on
7 were appropriate and reasonable.²¹ Furthermore, unlike Mr. Gorman's analytical results,
8 discussed previously, comparing the results of Ms. Bulkley's analysis to recently authorized
9 ROEs, Ms. Bulkley's analytical results and recommendations are within the range established by
10 recently authorized ROEs for other integrated electric utilities.²² While this demonstrates that Ms.
11 Bulkley's results are reasonable, the Company and the parties to the Settlement Agreement have
12 agreed to an ROE that is 60 basis points below Ms. Bulkley's recommendation and 25 basis points
13 below the Company's revised request, as one component of a more comprehensive settlement.
14 Therefore, the issue to be decided in this case at this time with respect to the ROE is whether or
15 not the Settlement Agreement ROE of 9.75% reasonably balances the interests of ratepayers and
16 shareholders.

17 **5. Fair Value ROR is reasonable and appropriate**

18 Although the Signatories agreed to a Settlement Agreement that includes a return on the
19 Fair Value increment of 1.0%, the DOD Brief focused on Ms. Bulkley's recommended return on
20 the Fair Value increment, not the settlement value of 1.0%.²³ However, Ms. Bulkley had
21 demonstrated that each component of the calculation is based on investors' expectations of
22 market conditions, and therefore her recommendation is reasonable.²⁴ Moreover, in her Rebuttal
23 Testimony, Ms. Bulkley updated her analysis, which resulted in a return on the Fair Value
24 increment of 1.07%.²⁵ The parties have agreed to a return on the Fair Value increment that is

25 ²¹ Ex. TEP-11 (Bulkley Rebuttal) at 55-77; Ex. TEP-12 (Bulkley Rejoinder) at 3-11.

26 ²² Ex. TEP-11 (Bulkley Rebuttal), Chart 1 at p. 12.

27 ²³ DOD Brief at 25-27.

²⁴ Ex. TEP-10 (Bulkley Direct) at 60-64, Exhibit AEB-10.

²⁵ Ex. TEP-11 (Bulkley Rebuttal) at 77, Ex. AEB-R-2; Tr. (Bulkley) at 262.

1 lower than Ms. Bulkley's updated recommendation. DOD's summary of Mr. Gorman's critique
2 of Ms. Bulkley's analysis is not relevant for the Commission's decision on the Settlement
3 Agreement. Rather, the Settlement Agreement provides for a return on the Fair Value increment
4 of 1.0%, which has been agreed to by the parties in the context of a broader agreement and that
5 amount is in the public interest.

6 **B. Energy efficiency program costs should not be included in base rates.**

7 TEP set forth its position on this issue in its Initial Post-Hearing Brief and stands by that
8 position.

9 **C. The \$16,000 TORS system should be in rate base.**

10 As of the end of the test-year, TEP had installed and was operating one TORS system
11 pursuant to the pilot program approved in Decision No. 74884 (December 31, 2014). The
12 system is used and useful and providing energy to TEP's customers. However, the amount at
13 issue is immaterial given TEP's \$2 billion rate base and has no impact on any rate or charge.
14 TEP understands that the remaining \$9,984,000 portion of the TORS program may be subject to
15 a prudency review in TEP's next rate case.

16 **III. The Commission should move towards a fair and cost-based revenue allocation.**

17 **A. CCOSS Methodology.**

18 Staff discusses the Company's Class Cost of Service Study ("CCOSS") in its opening
19 brief. Although the Company believes its CCOSS is appropriate, it does agree with Staff that the
20 CCOSS should be used as a guideline, not as a rigid structure, for revenue allocation decisions.

21 **B. Class Revenue Allocation.**

22 It appears that the parties who addressed this issue support a transition towards class
23 revenue allocations that reflect the actual class cost of service study. For example, Staff
24 indicates that "Staff's long-term plan is that rates should be based on costs derived from the
25 CCOSS, but that it will take more than one rate case to accomplish this goal."²⁶ Larger customer
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²⁶ Staff Brief at 12.

1 classes seek a greater movement towards such parity than either Staff or the Company.²⁷ The
2 Company's proposal on class revenue allocation is somewhere between the proposals of Staff
3 and the parties representing large customers, depending on the customer class. RUCO did not
4 take a position on revenue allocation in its brief, but supported Staff's allocation in testimony.²⁸
5 TEP has attached a table (as **Attachment 1**) that sets forth TEP's understanding of the current
6 revenue allocation positions.

7 As set forth in its Initial Brief, TEP believes its proposal takes the necessary first step in
8 moving class cost of service allocations in the right direction and provides the best opportunity to
9 reach parity in the next rate case. The other revenue allocation proposals also move towards
10 parity. Ultimately, how to move toward revenue allocation parity is a policy decision for the
11 Commission.

12 **IV. The LFCR must be improved to allow TEP to fully cover the lost fixed cost revenues**
13 **caused by the Commission's regulatory mandates.**

14 **A. The LFCR can and should be modified in this case.**

15 TEP's Opening Brief explains how the vast majority of TEP's fixed costs are recovered
16 through volumetric per kWh charges and cites to the extensive evidence in the record that supports
17 this. As billed kWh continues to fall, TEP is left with more and more unrecovered fixed costs.
18 This problem has been rapidly increasing, and revisions to the LFCR are needed to partially fix the
19 problem.²⁹ In particular, fixed generation costs and the remaining 50% of demand charges should
20 be included in the LFCR.³⁰ Without these changes, nearly 60% of TEP's lost fixed cost revenues
21 due to Commission EE and DG programs remain unrecovered.³¹

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25 ²⁷ See, e.g., Walmart Brief at 2-3; Freeport/AECC/Noble ("AECC") Brief at 8-9.

26 ²⁸ See Ex. RUCO-9 (Radigan Surrebuttal) at 11.

27 ²⁹ TEP Brief at 12-14.

³⁰ TEP Brief at 16-18.

³¹ Ex. TEP-7 (Hutchens Rejoinder) at 4:11-12; Ex. TEP-32 (Jones Rejoinder) at 7:2-6; see also Tr.
at 1089:23 to 1090:1 (Higgins)(accepting 41% figure).

1 Staff and AECC contend that the LFCR should remain hobbled by these restrictions,
2 arguing that the restrictions are part of the original intent of the LFCR.³² But TEP's current LFCR
3 was approved in a settlement—by definition a compromise of opposing views. That settlement
4 was for the purposes of that case only, and it did not purport to resolve the scope of the LFCR for
5 all time. Thus, TEP is free to propose, and the Commission is free to consider, appropriate
6 modifications to the LFCR to reflect the changes in circumstances since it was initially adopted.

7 Moreover, this case is very different from the last TEP rate case, because the lost fixed cost
8 revenue recovery problem is much greater than the last case. The problem is growing inexorably
9 year after year. TEP's brief showed how the unrecovered amount of lost fixed cost revenues—just
10 due to the Commission's EE and DG requirements—has grown from \$13 million in 2014, to
11 nearly \$20 million in 2015, to an estimated \$25.7 million in 2016.³³ These lost fixed cost
12 revenues are specifically intended to recover TEP's fixed costs of serving its customers, and these
13 lost revenues are specifically caused by the Commission's regulatory mandates—EE and DG. It is
14 reasonable and appropriate to make TEP whole for its compliance with these requirements.
15 Indeed, the Commission "must consider" in setting rates the costs of complying with Commission
16 mandates. *Ariz. Corp. Comm'n v. Palm Springs Util. Co., Inc.*, 24 Ariz. App. 124, 130, 536 P.2d
17 245, 251 (1975).

18 Further, TEP's brief explained how the specific language in the Commission's Decoupling
19 Policy Statement, the Commission's order in TEP's last rate case, and the Commission's order
20 earlier this year for UNS Electric all support having the LFCR fully address the lost fixed cost
21 problem caused by the Commission's EE and DG programs.³⁴

22 Thus, TEP's prior rate case settlement did not set the LFCR in stone. Both the ever-
23 expanding nature of the lost fixed cost problem and the Commission's own statements warrant
24 expanding the LFCR.

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³² Staff Brief at 12; AECC Brief at 14.

27 ³³ TEP Brief at 14:4-10.

³⁴ TEP Brief at 14-16.

1 **B. Fixed generation costs should be included in the LFCR.**

2 RUCO argues that generation should not be included in the LFCR because “purchased
3 power is fungible” and “the Company has many opportunities to adjust its energy supply”.³⁵
4 RUCO misses the point. The LFCR is limited to fixed costs. TEP’s proposal is to include fixed
5 generation costs. TEP has not proposed including purchased power costs in the LFCR; those costs
6 are not fixed and are flowed through the PPFA. Instead, TEP’s proposal is strictly limited to
7 fixed generation costs, i.e. fixed costs of generation units owned by TEP. These plants have long
8 operating lives and TEP cannot simply “adjust” them out of existence even if the volumetric kWh
9 intended to recover those fixed costs goes away. As TEP witness Jones explained, these “costs are
10 fixed plant costs and do not vary with consumption.”³⁶ RUCO cited Staff witness Solganick, but
11 he admitted under cross-examination that the LFCR changes proposed by TEP are “not intended
12 to recover purchased power costs.”³⁷ RUCO’s argument must be rejected.

13 Staff similarly argues that “generation is fungible, and is not affected by EE and DG if the
14 energy is delivered to a new customer, an existing customer using slightly more energy, an
15 economic development customer or sold off the system.”³⁸ The first three scenarios are for
16 increased retail sales. Any scenario with increasing retail sales is unrealistic—as Mr. Jones
17 explained, TEP “has experienced a loss in sales of over 270 GWh since the last test year.”³⁹ Staff
18 points to IRP projections to suggest that sales could go up, but Staff witness Solganick admitted
19 that those projections are dependent on “growth in mining loads”.⁴⁰ The IRP forecast was based
20 on increased load for the Rosemont and Freeport Sierrita mines—load that is far from certain, may
21 never materialize, but must be considered for planning purposes because TEP must stand ready to

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³⁵ RUCO Brief at 20.

25 ³⁶ Ex. TEP-31 (Jones Rebuttal) at 24:19.

26 ³⁷ Tr. (Solganick) at 2477:3-19.

27 ³⁸ Staff Brief at 13:20 to 14:1.

³⁹ Ex. TEP-31 (Jones Rebuttal) at 27:22-24.

⁴⁰ Tr. (Solganick) at 2479-80.

1 provide service if and when needed.⁴¹ Further, TEP witness Sheehan testified that these
2 preliminary forecasts would be downward to reflect more recent information.⁴²

3 Further, TEP has been clear that the “Company only desires to recover quantifiable lost
4 fixed costs associated with Commission mandated DG and EE losses.”⁴³ Therefore, TEP has
5 agreed to include an adjustment that would account for any increased retail sales in the LFCR if
6 the fixed generation costs are included.⁴⁴ Thus, Staff’s concerns about increased retail sales are
7 unfounded.

8 Staff’s argument about “off system” (i.e. wholesale) is equally baseless. Some of the fixed
9 generation costs are for “reliability must run” generation that is not available for off system
10 sales.⁴⁵ As for the remainder, off system sales are very difficult to make in the current market, and
11 if additional sales were to be made, they would likely be made at a wholesale market price well
12 below the full retail cost—so there is limited potential for TEP to dig itself out of the fixed cost
13 hole with off system sales.⁴⁶

14 Staff and RUCO also argue that adding generation into the LFCR could result in “double
15 collection” with the Economic Development Rider (“EDR”).⁴⁷ As described above, any increase
16 in retail sales will be accounted for in the LFCR. Moreover, the EDR is a discounted rate—and
17 thus not a way to recover fixed costs.

18 Finally, with respect to Staff’s concerns about the inclusion of generation fixed costs in the
19 LFCR, Staff seems to have the view that the recovery of these costs is an “all or nothing”
20 proposition. However, when asked if Staff’s concerns about potential over-collection would be
21 mitigated if TEP were allowed to recovery only 50% of lost generation fixed costs, Staff witness
22 Solganick simply replied that “50% is always less than everything.”⁴⁸

23 ⁴¹ See Tr. (Sheehan) at 1244-46.

24 ⁴² See Tr. (Sheehan) at 1244-46.

25 ⁴³ Ex. TEP-31 (Jones Rebuttal) at 28:4-6.

26 ⁴⁴ Ex. TEP-32 (Jones Rejoinder) at 6:13-15.

27 ⁴⁵ See TEP Brief at 17.

⁴⁶ See TEP Brief at 17.

⁴⁷ RUCO Brief at 20; Staff Brief at 14.

⁴⁸ Tr. (Solganick) at 2482.

1 **C. All lost demand charges caused by EE and DG should be included in the**
2 **LFCR.**

3 While Staff does not make a specific argument for excluding half of demand charges from
4 the LFCR, RUCO argues that “demand charges will remain constant or change slower than a
5 straight volumetric rate.”⁴⁹ If billed demand remained constant, there would be no problem.
6 However, there is a problem and, because only fixed costs are assigned to demand charges,
7 reductions in billing demand directly reduce fixed cost recovery.⁵⁰ Therefore, 100% of lost
8 demand charges attributable to EE and DG should be included, not the current 50%.

9 **D. The LGS class should not be exempt from the LFCR.**

10 AECC argues that the Large General Service (“LGS”) class should be exempt from the
11 LFCR.⁵¹ AECC suggests that the fixed cost recovery problem does not really apply to the LGS
12 class due to the LGS rate design. But the fixed cost recovery problem includes the LGS class. As
13 Mr. Jones explained, “LGS customers benefit from EE and DG programs, and TEP recovers a
14 large portion of the fixed costs to serve to them through volumetric rates.”⁵² Therefore, it is
15 appropriate to keep the LGS customers in the LFCR.

16 **E. SWEEP’s full decoupling option.**

17 SWEEP opposes the proposed expansion of the LFCR.⁵³ Yet SWEEP supports full
18 revenue decoupling.⁵⁴ This is an even broader expansion than proposed by TEP—under TEP’s
19 proposal, the LFCR would still be limited to lost fixed costs due solely to DG or EE mandates.
20 SWEEP’s objection therefore seems to be that the expansion proposed by TEP simply doesn’t go
21 far enough. TEP is not opposed to consideration of a properly designed full decoupling
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25 ⁴⁹ RUCO Brief at 21:5.

26 ⁵⁰ See TEP Brief at 18.

27 ⁵¹ AECC Brief at 14.

⁵² Ex. TEP-32 (Jones Rejoinder) at 9:12-14.

⁵³ SWEEP Brief at 19.

⁵⁴ SWEEP Brief at 19.

1 mechanism in the future, but TEP does not believe that a full decoupling mechanism has been
2 fully explored in this case.⁵⁵

3 **V. TEP's Residential and Small General Service ("SGS") rate design should be**
4 **approved.**

5 There does not appear to be any dispute that, under current rate design, TEP recovers a
6 significant portion of its fixed costs through volumetric rates. Currently, TEP collects about 89%
7 of its fixed costs through volumetric rates for residential customers (all but \$10 of the \$87 per
8 month in fixed costs to serve the average residential customer) and over 95% for SGS customers
9 (all but \$15.50 of the \$330 per month for the average SGS customer).⁵⁶

10 The record also reveals that customer usage is declining. Since end of the last test year
11 (2011), retail billed kWh are nearly 3% lower.⁵⁷ Residential billed kWh per customer has
12 dropped approximately 7.5% during the same period.⁵⁸ However, while billed kWh has been
13 declining, overall system demand has increased over the past year and TEP's fixed costs of
14 providing safe and reliable service must keep pace.

15 Given the evolving use of the grid, the current rate design results in increasingly
16 inequitable recovery of fixed costs from customers who rely upon the grid for safe and reliable
17 service. Cross-subsidies result when some customers are not paying their fair share of fixed
18 costs. TEP's proposed rate design changes are intended to: (i) begin to reduce the amount of
19 fixed costs recovered through volumetric rates; (ii) better align rate design with cost causation;
20 (iii) reduce the level of cross-subsidies among customers and customer classes; (iv) enhance the
21 Company's ability to recover its fixed costs; and (v) provide the Company with a more realistic
22 opportunity to achieve its annual revenue requirement.

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25 ⁵⁵ See TEP Brief at 19.

26 ⁵⁶ See Ex. TEP-45, Schedule G-6-1 (line 33); Ex. TEP-32 (Jones Rejoinder), Ex. CAJ-RJ-1,
27 Scheduled H-3, pages 6 and 17 of 23 (setting forth monthly customer charges). These percentages
may change slightly depending on the ultimate class revenue allocation.

⁵⁷ Ex. TEP-4 (Hutchens Direct) at 10-11.

⁵⁸ Ex. TEP-4 (Hutchens Direct) at 10-11.

1 TEP's rate design proposal is a gradual approach that begins to meet these goals. TEP
2 allocates approximately 40% of the revenue requirement increase for the residential and SGS
3 classes to the basic service charge and 60% to volumetric rates.⁵⁹ Both the basic service charge
4 and the volumetric rates will increase. Under TEP's proposed rate design – which is also
5 supported by Staff – TEP will still be recovering 83% of its fixed costs through volumetric rates
6 for standard residential customers (all but \$15 of \$87). This percentage will be higher for the
7 other residential rate options with a \$12 basic service charge. TEP also will be recovering
8 almost 92% of its fixed costs for SGS customers through volumetric rates.

9 TEP believes its rate design proposal comports with the Commission's acknowledgement
10 in the recent UNS Electric rate case decision that "the time is ripe for more modern rate design"
11 and that "outdated rate designs may contribute to under-recovery of fixed costs and may not
12 adequately reflect cost causation."⁶⁰ The Company agrees with the Commission that "Sending
13 the correct price signals to customers, avoiding misaligned subsidies and incentivizing
14 efficiencies and innovation are critical if peak system load is to be reduced and efficient use of
15 system resources is to be achieved – goals which benefit all ratepayers."⁶¹

16 However, several parties resist any rate design changes that will begin to better match
17 cost causation to cost recovery and to reduce the amount of fixed costs that are recovered
18 through volumetric rates. Remarkably, some parties argue for rate design that would recover
19 more fixed costs through volumetric rates, which would only exacerbate the current inequitable
20 recovery of fixed costs and resulting cross-subsidies. This mismatch between costs and revenues
21 leads to inappropriate price signals and the inability of the Company to recover its revenue
22 requirement due to declining kWh use per customer. TEP believes its rate design proposals are a
23 reasonable and gradual step towards equitable fixed cost recovery and a more modern and
24 appropriate rate structure. Staff has supported the key elements of this proposal as well.

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26 ⁵⁹ Tr. (Jones) at 2676.

27 ⁶⁰ Decision No. 75697 (August 18, 2016) at 65:22-23, 117:18-19.

⁶¹ Decision No. 75697 (August 18, 2016) at 117:19-22.

1 **A. Monthly Basic Service Charge.**

2 The uncontroverted evidence in this case establishes that the fixed monthly cost to serve
3 the average residential customer is approximately \$87.⁶² The Company's proposed basic service
4 charges are designed to recover costs that TEP incurs each month, which include meters, billing
5 and collection, meter reading, the service line or drop and the other components needed to form
6 the minimum system.⁶³ Staff agrees that recovery of these minimum system costs through the
7 basic service charge is appropriate.⁶⁴ This proposal helps recover fixed costs through a fixed
8 charge. Even with the Company's proposed increase in the basic service charge from \$10 to
9 \$15, TEP will still be recovering \$72 per month of its fixed costs through volumetric rates for
10 standard two part residential rates and more for the other residential rate options.⁶⁵

11 Several parties argue that the minimum system cost approach is improper and that the
12 basic customer method be used. However, the basic customer method greatly underestimates the
13 unavoidable fixed system costs needed to serve a customer. It also ignores the increasingly
14 diverse use of the grid that makes recovery of fixed costs through volumetric rates inequitable.
15 The basic customer method simply is not a method that uses accurate cost causation assumptions
16 or information⁶⁶, which results in an under-recovery of customer-related costs.

17 The two concerns voiced by several parties against a slightly higher basic service charge
18 are: (i) customers will be unable to "control" as much of their bills; and (ii) customers will have
19 less incentive to conserve energy. Both of these concerns are exaggerated and unfounded. First,
20 even under TEP's proposal, customers will control 83% of their bill, down slightly from the
21 current 89%. The recommendations of the parties for a lower basic service charge would
22 actually increase the mismatch of fixed cost recovery. RUCO admits that its rate design proposal
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25 ⁶² See Ex. TEP-45 (updated Schedule G-6-1 at Sheet 1 of 1).

26 ⁶³ See Ex. TEP-28 (Overcast Rebuttal) at 12-23; Ex. S-10 (Solganick Rate) at 28-30.

27 ⁶⁴ See Ex. S-10 (Solganick Rate) at 28-30.

⁶⁵ See Ex. TEP-45, Schedule G-6-1 (line 33)(fixed cost at \$87); Ex. TEP-32 (Jones Rejoinder), Ex. CAJ-RJ-1, Schedule H-3, page 6 of 23 (setting forth monthly customer charges).

⁶⁶ See Ex. TEP-28 (Overcast Rebuttal) at 17-20.

1 would lead to more than 90% of residential customer fixed costs being recovered by volumetric
2 rates.⁶⁷

3 Second, because there is a revenue requirement increase, the higher basic service charge
4 only covers a portion of the increase for the average customer. Indeed, the volumetric rate -
5 which is the driver for conservation - will actually be higher as well.⁶⁸ For example, the
6 volumetric rates for standard two-part rates in the summer will be \$0.0796/kWh for using more
7 than 500 kWh per month as compared to the current rates of \$0.0672/kWh for usage of 501 to
8 1000 kWh and \$0.0798/kWh for usage of 1,001 to 3,500 kWh.⁶⁹ In the winter, the comparison is
9 \$0.0796/kWh for using more than 500 kWh per month as compared to the current rates of
10 \$0.0652/kWh for usage of 501 to 1,000 kWh and \$0.0781/kWh for usage of 1,001 to 3,500
11 kWh.⁷⁰ Customers will continue to have at least equal incentive to conserve even with the
12 increased basic service charge under TEP's rate design proposal.

13 Further, several parties argue against an increase in the basic service charge by making
14 the absurd claim that TEP's ultimate goal is a basic service charge that matches the total fixed
15 costs to serve a customer. TEP witness Dallas Dukes stated, clearly and repeatedly, that this is
16 not the Company's objective.⁷¹ Those parties inexplicably ignore that any basic service charge
17 would have to be approved by the Commission.

18 Finally, the Commission has not required the "basic customer method" as the basis for
19 basic service charges. And none of the Intervenors have cited to any Arizona precedent that
20 requires application of the basic customer method. Indeed, the Commission just approved a
21 basic service charge for UNS Electric that reflected the Minimum System Method. The
22 Commission should do the same here.

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25 ⁶⁷ Tr. (Huber) at 1657.

26 ⁶⁸ See Ex. TEP-32 (Jones Rejoinder), Ex. CAJ-RJ-1, page 6 of 23.

27 ⁶⁹ See Ex. TEP-32 (Jones Rejoinder), Ex. CAJ-RJ-1, page 6 of 23.

⁷⁰ See Ex. TEP-32 (Jones Rejoinder), Ex. CAJ-RJ-1, page 6 of 23.

⁷¹ Ex. TEP-21 (Dukes Direct) at 15-16; Tr. (Dukes) at 1367.

1 **B. Reducing the Number of Volumetric Tiers.**

2 TEP has proposed eliminating two of the four volumetric tiers for its residential rates.
3 Staff agrees that the number of tiers should be reduced.⁷² While four tiers may have been
4 appropriate during times of consistent customer load growth and before the proliferation of DG
5 and EE, it is no longer appropriate given the significant changes in electricity usage patterns in
6 TEP's service territory. Opponents of eliminating the top two volumetric tiers argue that doing
7 so would reduce the incentive for customers to adopt DG or EE. However, the record is clear
8 that eliminating the top two tiers better aligns the rate design with cost-causation⁷³ and reduces
9 the excess recovery of fixed costs from customers whose usage pushed into the third tier.⁷⁴ The
10 higher tiers also do not send appropriate price signals to customers. Staff witness Solganick also
11 urges that the remaining inclination of the tiers should be flattened to send better price signals.⁷⁵

12 The top two tiers are a significant driver of intra-class cross-subsidization and has
13 contributed to the Company's inability to earn its Commission-authorized revenue requirement.⁷⁶
14 Moreover, as set forth above, under the Company's standard residential rate proposal, the
15 volumetric rate in the second tier is almost identical to the rate in the current third tier, so almost
16 all customers will have basically the same incentive to conserve. Moreover, as discussed in
17 TEP's Initial Post-Hearing Brief, only 0.5% of bills would be impacted by the elimination of the
18 fourth tier.⁷⁷

19 RUCO continues to wrongly assert that 41% of customers who are higher usage
20 customers will see a rate decrease in the summer if the number of tiers is reduced.⁷⁸ That is
21 assertion is wrong for several reasons. First, as the Company has explained, that analysis fails to
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24 ⁷² Staff Brief at 16.

25 ⁷³ Ex. TEP-30 (Jones Direct) at 45.

26 ⁷⁴ Ex. TEP-30 (Jones Direct) at 45.

27 ⁷⁵ Tr. (Solganick) at 2471-72; Ex. S-10 (Solganick Rate) at 29.

⁷⁶ See Ex. TEP-30 (Jones Direct) at 41-45.

⁷⁷ TEP Brief at 25.

⁷⁸ RUCO Brief at 19.

1 include the fuel rates.⁷⁹ Second, it ignores that the proposed volumetric rates will be higher for
2 the first and second tier.⁸⁰ When those elements are factored in, the number is basically 0%.⁸¹

3 Finally, the record also shows that multiple tiered rates are not helpful to customers. The
4 Company receives many customer complaints, particularly in the summertime, when customers
5 hit the higher tiers and see that they have to pay higher rates when they use more energy.⁸² The
6 Company is not proposing to eliminate all tiers at this time, but eliminating the top two tiers will
7 mitigate issues regarding inequitable fixed cost recovery and cross-subsidies.

8 **C. TEP's proposed Time-of-Use ("TOU") rate modifications are reasonable.**

9 TEP has proposed significant modifications to its residential TOU rates, as described in
10 TEP's Initial Brief.⁸³ TEP is adjusting the peak periods, making the basic service charge lower
11 than the standard two-part rate, adding a volumetric tier and increasing the spread between on-
12 peak and off-peak volumetric energy rates. These significant changes are intended to increase
13 customer adoption of the TOU rate.

14 Other parties seek radical changes to the current TOU rate, such as 3-4X spreads between
15 on-peak and off-peak rates, and off-peak rates of \$0.01/kWh (which are far below marginal cost
16 and sends poor price signals.) TEP is concerned that such radical changes could result in
17 increased intra-class subsidies or other unintended consequences. TEP's significant, yet more
18 gradual modifications to its TOU rates are more appropriate.

19 **D. TEP's Low Income Discounts are appropriate.**

20 TEP believes its increased discounts for Lifeline customers are reasonable. Although some
21 concern was raised about a handful of Lifeline customers on a few of the frozen Lifeline rates that
22 may see a larger percentage increase, no concrete proposals have been provided. Under TEP's
23 proposal, those customers will receive a discount of almost \$500 per year (\$40 per month).⁸⁴ TEP

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25 ⁷⁹ Ex. TEP-31 (Jones Rebuttal) at 37-38.

26 ⁸⁰ Ex. TEP-31 (Jones Rebuttal) at 37-38.

27 ⁸¹ Ex. TEP-31 (Jones Rebuttal) at 37-38.

⁸² Ex. TEP-31 (Jones Rebuttal) at 35-36; Tr. (Jones) at 2582-84

⁸³ TEP Brief at 25.

⁸⁴ Ex. TEP-31 (Jones Rebuttal) at 22:1-8; Ex. TEP-32 (Jones Rejonder), Ex. CAJ-RJ-2.

1 is already proposing to increase Lifeline discounts from \$1.8 million to \$2.8 million in this rate
2 case.⁸⁵ To the extent this discount is increased, other TEP customers will bear the cost.

3 With respect to ACAA's request to develop a sliding scale for Lifeline discounts, the
4 Company intends to assess the feasibility of such an approach and may propose such a program in
5 its next rate case.

6 **E. TEP's SGS Rate Design is in the public interest.**

7 TEP is proposing changes to its SGS rate design that are similar to its residential rate design
8 changes. These changes should be approved for the same reasons as for the residential changes.

9 **F. The discount for certain governmental entities should be eliminated.**

10 TEP is proposing to eliminate the current 16.5% transitional discount for certain
11 governmental entities.⁸⁶ The only party opposed to its elimination is Pima County. However,
12 Pima County presented no testimony as to why it should continue to be entitled to something that
13 is nothing more than a subsidy from TEP's ratepayers. Any reduced cost recovery resulting from
14 the discount would be passed on to other TEP ratepayers.

15 **VI. MGS, LGS and other commercial rate design issues.**

16 **A. The new MGS is necessary and appropriate.**

17 TEP is proposing the creation of a Medium General Service ("MGS") class, similar to
18 what the Commission recently approved for UNS Electric. As set forth in TEP's Initial Brief,
19 creating the MGS class is an important step in modernizing TEP's rates and better matching cost
20 recovery to cost causation. The MGS class also will provide for more equitable rates. The larger
21 current SGS customers tend to use the grid more efficiently and have a higher load factor.⁸⁷ Under
22 the two-part SGS rates, those larger customers are going to pay a much higher proportion of the
23 costs assigned to the SGS class.⁸⁸ Those customers will likely benefit from moving to the MGS

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26 ⁸⁵ Ex. TEP-31 (Jones Rebuttal) at 22:

27 ⁸⁶ Ex. TEP-30 (Jones Direct) at 46:11-19.

⁸⁷ See Tr. (Jones) at 2795-96.

⁸⁸ Tr. (Jones) at 2796.

1 rate. Indeed, TEP's analysis of bill impacts for transitioning SGS customers reveals that many
2 will see bill reductions from being on the MGS rate.⁸⁹

3 Staff supports the creation of the MGS class. Staff has made recommendations regarding
4 the MGS class and TEP agrees to Staff's recommendations.

5 The MGS class is opposed primarily by two solar parties, EFCA and SOLON. These
6 parties complain primarily about the potential imposition of a demand element on MGS
7 customers. Although solar providers seem to universally oppose demand rates because their
8 products may not reduce demand or be as cost-effective, their specific concerns about the MGS
9 class are unfounded.

10 First, their concerns about ratchets ignore the purpose and benefits of ratchets. TEP
11 discussed the application of ratchets in depth in its Initial Brief.⁹⁰ If ratchets are eliminated, there
12 will be an increase in the various rate elements – in particular, the demand rate would certainly
13 increase. Further, the concerns about the impact of ratchets on outlier seasonal customers is
14 addressed in TEP's MGS tariff, which provides an exception for extreme seasonal issues.⁹¹

15 Second, the concern that the larger SGS customers that will transition to MGS will not be
16 able to understand or manage demand underestimates those customers. TEP and Staff have agreed
17 upon an extended transition period and related customer education plan. The new MGS customers
18 will not be subject to an actual demand charge until the transition plan is complete, which TEP has
19 not opposed extending from 9 to 12 months.⁹²

20 Finally, the solar parties raise a concern that MGS customers will not be notified if they are
21 eligible to move back to SGS rates. However, such notification is not typically done with respect
22 to commercial and industrial rate classes.

23 Pima County also has requested that governmental customers be exempted from the MGS
24 tariff, even though such a customer would qualify as MGS. In effect, Pima County is seeking to
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26 ⁸⁹ See Ex. TEP-43 (Table re SGS to MGS bill impacts).

27 ⁹⁰ TEP Initial Brief at 33-35.

⁹¹ TEP Initial Brief at 34-35.

⁹² Tr. (Jones) at 2779.

1 have all governmental SGS customers grandfathered on the SGS rate. However, Pima County
2 presented no evidence explaining why such grandfathering is in the public interest and did not
3 raise the issue until briefing. Its tardy assertions about governmental customers in its brief cannot
4 be tested by cross-examination. Moreover, there are likely several governmental customers that
5 have higher load factors and will benefit from the MGS rate. Such limited and potentially
6 discriminatory grandfathering is inappropriate.

7 **B. Current SGS DG Customers that qualify for MGS will be grandfathered on**
8 **the two-part transitional MGS rates.**

9 TEP confirms its position that current SGS DG customers who would be transitioned to the
10 MGS class will be able to remain on two-part transitional MGS rates (should they request to do
11 so) as of the grandfathering cut-off date (and for the grandfathering period) set by the Commission
12 in Phase 2.

13 **C. TEP's LGS Customers generally support the proposed LGS Rate.**

14 Kroger, an intervenor in this proceeding, supports TEP's proposed LGS rate design.⁹³
15 Wal-Mart, also an intervenor, appears to generally support the LGS-TOU rate but would like to
16 have a larger amount of the class revenues recovered through the demand charge.⁹⁴

17 SOLON opposes the proposed LGS rate because it fears that the demand rate and ratchet
18 risk curtailing solar and conservation. However, the current LGS tariff has demand rates and
19 ratchets and several of TEP's current LGS customers have solar.⁹⁵ In the last two years, LGS
20 customers with solar systems have increased from 5.4% to 7.1% and LPS customers with solar
21 have increased from 11.1% to 26.3%.⁹⁶ Moreover, LGS customers always have incentive to
22 conserve energy and demand rates provide the ability to reduce *both* usage and demand.

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26 ⁹³ Kroger Brief at 2-3.

27 ⁹⁴ Wal-Mart Brief at 5.

⁹⁵ Ex. TEP-32 (Jones Rejoinder) at 14.

⁹⁶ Ex. TEP-32 (Jones Rejoinder) at 14.

1 **VII. The Commission should approve the proposed DG meter charge.**

2 There is no dispute that rooftop solar customers have a second meter, that the second meter
3 imposes an additional cost on the Company, or that this second meter is needed for TEP to comply
4 with Commission requirements. The parties that oppose the DG meter charge argue that the
5 charge does not benefit DG customers specifically, so the extra cost of the second meter should be
6 borne by all customers, not just the DG customers. These meters do provide benefits to DG
7 customers, who can use them to monitor the output of their solar system.⁹⁷ In any event, the
8 regulatory principle is that costs should be assigned to cost causers. The test is not who benefits,
9 but who causes the cost. Here, the second meters would not be installed except for the customer
10 installing the solar system. Thus, that customer should bear the cost; the cost should not be shifted
11 to other customers as it is today.

12 Importantly, this charge will only apply to new meters installed for new solar DG
13 customers. Some parties dispute the amount of the cost, but TEP's approach is very conservative.
14 Because the charge only applies to new meters, the historical (embedded) cost of meters is
15 irrelevant; the relevant cost is the marginal (incremental) cost—i.e. what a new meter actually
16 costs today.

17 Mr. Koch argues that the DG meter charge should apply only if customers can opt out from
18 the second meter, and thus, opt out of the charge as well.⁹⁸ But the second meter is required to
19 comply with Commission rules and requirements, so this is not an option.⁹⁹

20 **VIII. The Economic Development Rider should be approved.**

21 In the opening briefs, two parties expressly supported the EDR.¹⁰⁰ No other parties raised
22 any significant issues about the EDR in the initial briefs. The Company requests the
23 Commission approve the EDR as it did for TEP's sister company, UNS Electric.¹⁰¹

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25 ⁹⁷ TEP Brief at 40.

26 ⁹⁸ Koch Brief at 2.

27 ⁹⁹ TEP Brief at 39-40.

¹⁰⁰ Walmart Brief at 5-6; AIC Brief at 15.

¹⁰¹ Decision No. 75697 (August 18, 2016) at 89-90.

1 **IX. The risky and illegal buy-through proposals must be rejected.**

2 **A. Buy-through programs benefit only a select few, at the expense of others.**

3 TEP's Opening Brief explained why the various buy-through proposals are premature,
4 harmful to customers, and illegal.¹⁰² Neither Staff nor RUCO support the buy-through
5 proposals.¹⁰³ The buy-through proponents (AECC, Freeport, Noble, Walmart, and Kroger) tout
6 the benefits they would receive under the program. True enough. But the evidence demonstrates
7 that each buy-through proposal would harm other customers by:

- 8 • increasing the average cost of TEP's generation supply (by eliminating low cost purchased
9 power resources, which they would hoard for themselves);¹⁰⁴
- 10 • shifting fixed generation costs to other customers;¹⁰⁵
- 11 • creating returning customer risk;¹⁰⁶ and
- 12 • subjecting TEP to counterparty risk with the buy-through provider.¹⁰⁷

13 Further, the buy-through proposals are premature. Any Commission decision on buy-
14 through programs should wait until the APS AG-1 buy-through program is evaluated in APS's
15 pending rate case.¹⁰⁸

16 AECC argues that customers will benefit from the buy-through programs because TEP will
17 be able to defer building or acquiring new generation.¹⁰⁹ But a buy-through customer could return
18 at any time, or the buy-through provider could fail to deliver at any time.¹¹⁰ TEP must stand ready
19 to provide generation service to any buy-through customers at a moment's notice; thus no
20 planning or other reductions are achieved. The real issue is the recovery of the fixed costs of the

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22 ¹⁰² TEP Brief at 41-50.

23 ¹⁰³ Staff Brief at 18-24 (Staff does not oppose buy through as long as "there are no adverse
impacts or costs to all other customers", [22:14-15] but this condition has not been proven);
RUCO Brief at 23-24.

24 ¹⁰⁴ TEP Brief at 42-45.

25 ¹⁰⁵ TEP Brief at 44:1-4, citing Ex. TEP-32 (Jones Rejoinder) at 10.

26 ¹⁰⁶ TEP Brief at 44:5-17.

27 ¹⁰⁷ TEP Brief at 44:18 to 45:5.

¹⁰⁸ TEP Brief at 41-42.

¹⁰⁹ AECC Brief at 17.

¹¹⁰ TEP Brief at 44.

1 current generation units used to serve TEP's customers—the buy-through proponents do not want
2 to pay their fair share of these costs.

3 At the hearing, TEP witness Sheehan testified that under TEP's original buy-through
4 proposal, in 2017, the PPFAC rate would increase by 0.5 mils for TEP's residential and
5 commercial customers if a 60 MW buy-through program is approved. This is because lower cost
6 purchased power is removed from the generation mix and allocated to the buy-through customers
7 instead.¹¹¹ This would represent an increase of 1.0 to 1.5% in PPFAC-eligible costs.¹¹² AECC
8 argues that this analysis is flawed.¹¹³ In addition, AECC states that the loss of a 60 MW industrial
9 load could simply be resold into the wholesale market at roughly the same price as the Company's
10 average cost of fuel and purchase power, thus having no impact on remaining customers.

11 In reality, the assumption that the 60 MW loss of industrial load would simply net out
12 through additional sales into wholesale market on a megawatt-hour by megawatt-hour basis is
13 unrealistic given the fact that wholesale power prices are projected to be lower than the
14 Company's incremental cost of fuel for a number of periods throughout the year.

15 Furthermore, a number of the PPFAC eligible costs are fixed and cannot be avoided on a
16 short-term basis. Therefore, a re-dispatch of the Company's generation portfolio would result in a
17 higher average cost of fuel and purchase power from the loss of buy-through customers since the
18 PPFAC eligible costs would be allocated over fewer kilowatt hour sales. This is just common
19 sense—removing a low cost resource from the generation resource mix will raise the average cost
20 for remaining customers.

21 AECC suggests that the buy-through program is a superior economic development tool to
22 TEP's proposed EDR.¹¹⁴ That is not the case. The EDR is specifically targeted at true economic
23 development—adding new business customers or existing business customers expanding their
24 operations. In contrast, a buy-through customer could reduce operations and lay off staff, and still

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26 ¹¹¹ Tr. (Sheehan) at 1238-39.

27 ¹¹² Tr. (Sheehan) at 1239:6-8.

¹¹³ AECC Brief at 20-21.

¹¹⁴ AECC Brief at 22.

1 qualify for the program. Moreover, the EDR is designed to attract high load factor customers that
2 will benefit the entire system. In contrast, the buy-through program benefits only the buy-through
3 customers and the providers eager to sidestep Commission oversight to sell to them.

4 **B. The buy-through program is illegal.**

5 Only AECC tries to defend the legality of a buy-through program.¹¹⁵ AECC points to
6 A.R.S. § 40-202(B) as supporting competition. This subsection was enacted as § 23 of Laws
7 1998, Ch. 209. The 1998 Act provides a framework for electric competition, but it also allows the
8 Commission to control whether competition is allowed, under what terms, and by whom. The
9 1998 Act permits competition only by “electricity suppliers”, who are regulated public service
10 corporations. A.R.S. § 40-201(14). Electricity suppliers are authorized to provide service if they
11 receive certificates from the Commission. A.R.S. § 40-207. No such certificates remain in effect.
12 The CC&Ns of the traditional electric utilities remain in effect, and their service territories are
13 opened only to electricity suppliers certificated by the Commission. A.R.S. §§ 40-208; 30-308
14 (same for service areas of public power entities). The buy-through proposals do not comply with
15 these requirements. The buy-through providers do not have electricity supplier certificates, so
16 they are not permitted to provide service. Nor have the buy-through providers accepted regulated
17 public service corporation status, as is required by the 1998 Act. For example, because electricity
18 suppliers are public service corporations, they are required to file tariffs with the Commission.
19 A.R.S. § 40-365 (“every public service corporation shall file with the commission” a schedule of
20 rates and charges). The buy-through rates (or “prices”) would not be tariffed. In short, the buy-
21 through proposals fail to meet the requirements of the 1998 Act.

22 TEP’s Opening Brief also explains how the buy-through programs violate the “fair value”
23 requirement of the Arizona Constitution and the Management Interference Doctrine.¹¹⁶ The buy-
24 through proponents have not addressed these issues in their opening briefs. Further, the APS AG-
25 1 Tariff was agreed to by APS and was never challenged on appeal.

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27 ¹¹⁵ AECC Brief at 30-32.

¹¹⁶ TEP Brief at 45-48.

1 AECC argues that the buy-through proposals “are similar to third-party providers of
2 rooftop solar units”.¹¹⁷ But rooftop solar providers sell equipment, not electricity. Rooftop solar
3 leasing companies claim that is all they are doing, as well. Perhaps that is a claim that this
4 Commission should investigate—but for the moment at least, solar leasing companies are being
5 treated as though they do not sell electricity.¹¹⁸

6 AECC also points to TEP’s TORS and RCS programs.¹¹⁹ But these are regulated
7 programs offered by the regulated public service corporation. They are not precedent for
8 unregulated buy-through providers selling power to customers at untariffed and unregulated
9 prices.

10 **X. Freeport’s “Franchise Agreement” is neither legal nor wise.**

11 Freeport argues that the Commission should unilaterally impose a franchise “agreement”
12 on TEP, to allow Freeport’s affiliate Morenci Water & Electric (“MWE”) to serve the Sierrita
13 mine in TEP’s service territory. Freeport complains that, “TEP’s approach to economic
14 development and sustainability has been lacking in both effort and originality.”¹²⁰ In reality, TEP
15 has worked hard to assist Freeport, and Freeport benefits from numerous rate advantages
16 supported by TEP and approved by the Commission.¹²¹ TEP has also proposed the EDR and is
17 open to other suggestions to promote economic development. Freeport complains that APS has
18 proposed a special high load factor rate and a special contract for them. But TEP has proposed a
19 special 138 kV rate for Freeport, and the record is devoid of any evidence that Freeport has asked
20 for a special contract from TEP.

21
22
23 ¹¹⁷ AECC Brief at 31:22.

24 ¹¹⁸ The Commission has previously determined that SolarCity Corporation was not a public
25 service corporation, basing its analysis on the Solar Service Agreements (SSA) formerly used by
26 SolarCity. Decision No. 71795 (July 12, 2010). The Commission has not examined the more
recent solar leasing model, and the Commission has not directly ruled on legal status of solar
leasing companies.

27 ¹¹⁹ AECC Brief at 31:19-21.

¹²⁰ AECC Brief at 29:19-20.

¹²¹ See TEP Brief at 50.

1 Freeport argues that its franchise “agreement” would insulate TEP and its customers from
2 the fixed cost impacts of a closure of Sierrita.¹²² But fixed costs are just that, fixed, and they don’t
3 go away just because MWE takes over service to Sierrita. Freeport has not proposed reassigning
4 those fixed costs to other customers. But that is what should be done if the franchise proposal is
5 approved, as the loss of the Sierrita billing determinants will be known and measurable if the
6 franchise proposal is approved. This harm to other customers is another reason to reject the
7 proposal.

8 Lastly, Freeport argues that MWE holds ACC and FERC certificates.¹²³ MWE’s
9 certificate is a traditional electric CC&N, which restricts MWE to serving its designated service
10 area. MWE does not have a competitive electric supplier certificate under A.R.S. § 40-207, and it
11 is not authorized or allowed to sell electricity outside of its designated service area.

12 Freeport offers no assurances at all that jobs or economic activity would be maintained or
13 increased at Sierrita if the franchise proposal is approved.¹²⁴ TEP does not agree to this
14 “agreement”, and MWE cannot serve in TEP’s certificated area without both TEP’s consent and
15 Commission approval.

16 The Commission has other tools at hand if it believes that Freeport needs assistance. Chief
17 among them is the revenue allocation. TEP would not oppose moving the revenue allocation
18 closer to cost parity. That would be a more principled approach than approving a legally doubtful
19 and economically unsound special deal for Freeport.

20 **XI. AECC’s proposed changes to the PPFAC should be rejected.**

21 **A. PPFAC “sharing” is risky and unsupported.**

22 As a regulated utility, TEP carefully manages the costs of purchased power and fuel for its
23 customers. TEP follows conservative procurement and hedging policies. These policies have
24 been reviewed by the Commission Staff, and TEP files updates with the Commission whenever
25 these policies change. Under the PPFAC, all purchased power and fuel costs are passed through

26 ¹²² AECC Brief at 30.

27 ¹²³ AECC Brief at 30.

¹²⁴ TEP Brief at 51.

1 to customers without any profit margin. TEP's purchased power and fuel procurement is designed
2 to prudently hedge forward power and natural gas while protecting customers from unexpected
3 price volatility.

4 AECC would turn this sensible system on its head. AECC argues that "without risk, there
5 is little incentive for the Company to keep power and fuel costs down."¹²⁵ TEP strongly objects to
6 this statement. TEP prudently executes its on-going fuel and purchased power procurement to
7 keep these costs low, and TEP stands by its record in doing so. No party has presented even a
8 shred of evidence to the contrary. No party has brought forward any procurement practice that
9 should be changed, any transaction that should or should not have been completed, anything that
10 TEP could have done but did not. Moreover, TEP has strong incentives to keep purchased power
11 and fuel costs as low as possible.

12 AECC's plan would have TEP focused on profits, not customers. Surprisingly, RUCO
13 now supports a variation of this proposal, with 80/20 "sharing", as opposed to the 70/30 proposed
14 by AECC.¹²⁶ But RUCO merely cites AECC's witness Mr. Higgins, and it offers no new evidence
15 of its own in support of this risky proposal.

16 These "sharing" proposals are not about risk management or hedging. Indeed, AECC
17 witness Higgins admitted, his "sharing" proposal increases TEP's risk.¹²⁷

18 AECC's "sharing" mechanism does not measure the prudence of TEP's procurement. As
19 Mr. Higgins explained, under his proposal, the Commission will approve projected purchased
20 power and fuel costs for 2017; if the Company beats the projected costs, it gets 30% of the
21 "profits"; conversely, if the Company's costs are higher than the projection, the Company must
22 absorb 30%.¹²⁸ As TEP witness Robey aptly explained, this is merely a test of the forecast, not a
23 test of the prudence of TEP's procurement transactions.¹²⁹

24
25 ¹²⁵ AECC Brief at 15.

26 ¹²⁶ RUCO Brief at 22-23.

27 ¹²⁷ Tr. (Higgins) at 1043.

¹²⁸ Tr. (Higgins) at 1045.

¹²⁹ Ex. TEP-38 (Robey Rebuttal) at 7-9.

1 Mr. Higgins even suggests that the management of these energy costs are not outside the
2 Company's control.¹³⁰ In truth, a majority of the fundamental drivers in a forward projection of
3 fuel and purchase costs are in fact outside the Company's control. This includes price volatility of
4 natural gas and wholesale power, large shifts in customer usage projections,¹³¹ intermittent output
5 of renewable generation resources, as well as unforeseen acts of nature that create market events
6 that lead to unforeseen price spikes.¹³²

7 As Company witness Robey explained, adjustor plans of administration ("POA") carefully
8 take into account the degree to which things are and are not within a utility's control: "Each of the
9 plans of administration cited by Mr. Higgins feature complex delineations between what is and
10 what is not within the utilities' control. For those items deemed not to be in the utilities' control,
11 there are balancing components created to make up for differences in actual performance versus
12 what was originally projected in the forecast."¹³³ None of the details regarding these
13 unpredictable factors within these proposed sharing mechanisms were ever addressed by AECC or
14 any other party to this proceeding.

15 AECC has only opined on so-called 'benefits' of their proposed sharing mechanism
16 without providing any specific details on how the Company's PPFAC POA would need to be
17 modified. In actuality, AECC's proposal would require burdensome annual regulatory reviews
18 that would necessitate significant changes to the POA to address a number of forecast modeling
19 and regulatory rate complexities.¹³⁴ Given this unsupported detail, AECC's PPFAC sharing
20 mechanism should be rejected.

21 In summary, AECC's proposal would make TEP try to play the market, rather than
22 continue with its prudent, conservative and Commission-reviewed procurement and hedging
23

24 ¹³⁰ Ex. AECC-6 (Higgins Direct) at 39-40.

25 ¹³¹ Freeport McMoran's 2016 announced mining curtailments.

26 ¹³² A number of historical events have resulted in market anomalies that resulted in unforeseen
price spikes (i.e., regional forest fires, regional transmission outages, gulf coast hurricanes, and
extremely cold weather conditions that disrupted natural gas transportation availability).

27 ¹³³ Ex. TEP-38 (Robey Rebuttal) at 9.

¹³⁴ Ex. TEP-38 (Robey Rebuttal) at 9.

1 policies. In reality, AECC's proposal tests the forecast, not the wisdom or prudence of TEP's
2 procurement. To a large extent, TEP's purchased power and fuel costs are outside of its control.
3 These are costs of service that should be passed through to customers. AECC has not provided
4 sufficient details about how this risky and complex scheme would work. AECC's proposal should
5 be rejected.

6 **B. The PPFAC's treatment of long-term sales should not be changed.**

7 Relatedly, AECC argues that the PPFAC's treatment of margin on long-term off-system
8 sales should be changed.¹³⁵ Currently, the margin from short-term off-system sales is credited to
9 customers in the PPFAC, while long-term sales are accounted for in the jurisdictional allocation.
10 AECC argues that the treatment of long-term wholesale margin was changed in the last rate case.
11 That is simply wrong. The operation of the PPFAC did not change in the last rate case. In that
12 case, the settlement approved a clarification that codified the existing practice of how the PPFAC
13 worked. The clarification was based on the Federal Energy Regulatory Commission ("FERC")
14 definition of wholesale power transactions that distinguishes between short-term sales and long-
15 term sales. Long-term wholesale sales have received the same treatment since the inception of the
16 Company's PPFAC in 2008.¹³⁶

17 AECC also argues that the 2017 wholesale transaction with Navopache Electric
18 Cooperative was not disclosed in the rate case and no fixed generation costs were allocated to the
19 Navopache contract.¹³⁷ This is flat out wrong. In fact, in TEP's Rebuttal Testimony, the
20 jurisdictional allocation demand factor was revised to include the new long-term Navopache
21 contract.¹³⁸ This was then carried over into the revenue requirement approved in the Settlement
22 Agreement.¹³⁹

23
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25 ¹³⁵ AECC Brief at 16.

26 ¹³⁶ Ex. TEP-39 (Robey Rejoinder) at 8.

27 ¹³⁷ AECC Brief at 16:11-21.

¹³⁸ Ex. TEP-25 (Sheehan Rebuttal) at Exhibit MES-R-1 (Jurisdictional Allocation Demand Factor).

¹³⁹ Ex. TEP-3 (Settlement Agreement) at Attachment A, page 3 of 5.

1 No change is warranted for the treatment of long-term off-system sales in the PPFAC.
2 Long-term sales are FERC jurisdictional transactions and are already addressed in the
3 jurisdictional allocation. The jurisdictional allocation specifically allocates a pro-rata share of the
4 non-fuel related costs directly to long-term wholesale contract customers. As such, TEP's retail
5 customers benefit from lower overall rates due to the allocation of fixed generating costs being
6 spread over a larger customer base. AECC's proposal results in asymmetrical benefits for large
7 industrial customers. AECC's proposal only kicks in if long-term wholesale sales increase. If
8 AECC's proposal were symmetrical, it would also account for reduced long-term wholesale sales.
9 If long-term wholesale sales fall between rate cases—a reasonable scenario in this weak market—
10 the jurisdictional allocation will assume that those revenues are still there to support those fixed
11 costs, but in reality the revenues will be lost. AECC is notably silent about this scenario.

12 AECC's proposal is one-sided, unnecessary, and contrary to how the PPFAC has worked
13 from inception. AECC's proposal should be rejected.

14 **XII. Other Issues.**

15 **A. Prepay Pilot Program.**

16 Staff has continued to support the Prepay pilot program and has summarized its
17 recommendations for the program in its initial brief.¹⁴⁰ The Company agrees with Staff's
18 recommendations.

19 ACAA opposes implementation of the pilot program. Despite ACAA's opposition to the
20 prepay program, Ms. Zwick acknowledged the following while on the stand:

21
22 Q. And would you agree that if the Commission was to approve this pilot program
23 that the company, the Commission, and other stakeholders will have the benefit of
24 the information and experience derived from this program to determine whether in
the future it should continue or be modified or eliminated?

25 A. I would hope so, and I would hope that we would be able to help participate in
the criteria that are used.

26 ...
27

¹⁴⁰ Staff Brief at 29-30.

1 Q. Might there be some low income customers that participate in this program that
2 thrive with it and do not have a detriment?

3 A. Possibly, and I guess that's what would be interesting to see.¹⁴¹
4

5 As set forth in the record and TEP's Initial Brief, there are many benefits from the Prepay program
6 that can be confirmed through the pilot program. ACAA's concerns should not preclude a pilot
7 program that would collect TEP-specific information.

8 **B. Deposits from Low-Income Customers.**

9 ACAA requests that low-income customers be excused from paying a deposit when they
10 are delinquent more than twice in a year or have been disconnected for service. The Company
11 continues to disagree that low-income customers should be treated differently than other
12 customers with respect to deposits. ACAA's proposal regarding deposits was not adopted in the
13 UNS Electric rate case and should not be adopted here.¹⁴²

14 **C. Auto-Enrollment of Low-Income customers in a Lifeline Tariff**

15 ACAA has requested that the Company automatically enroll customers who receive energy
16 assistance in the Lifeline program. ACAA states that the Company should recover the costs of
17 enrolling additional Lifeline customers through one of its adjustor mechanisms.¹⁴³ ACAA
18 requests an implementation plan, with input from interested stakeholders, be prepared within 90
19 days of rates going into effect. Neither of these concepts (an implementation plan nor the
20 recovery of auto-enrollment costs through an adjustor) were set forth in testimony and are
21 insufficiently defined to be approved now.

22 TEP intends to follow the Commission's guidance in the recent UNS Electric rate order, in
23 conjunction with UNS Electric, and will investigate how to implement automatic enrollment.
24
25

26 ¹⁴¹ See Tr. (Zwick) at 630-31.

27 ¹⁴² Decision No. 75697 (August 18, 2016) at 131-32; See Tr. (Zwick) at 636.

¹⁴³ See ACAA Brief at 26-27.

1 **D. Payment Centers.**

2 In its Opening Brief, ACAA asserts that “In 2007 ALL the major utilities in Arizona
3 including UNSE, UNSG and TEP, agreed to no longer accept payments through payday lenders . .
4 .”¹⁴⁴ That statement is incorrect. In 2007, UNS Electric, UNS Gas and TEP agreed to no longer
5 actively promote payday lending businesses as payment centers and to identify other payment
6 locations. During the 2008 UNS Gas Rate Case hearing, it was confirmed that Wal-Mart stores
7 were accepting payments for UNS Gas.¹⁴⁵ This payment process was also available for UNS
8 Electric and TEP.¹⁴⁶ Company witness David Hutchens further testified that the Company had
9 removed the link to ACE Cash Express (“ACE”) from the Company’s website in response to Ms.
10 Zwick’s request.¹⁴⁷ The service agreement with ACE executed in 2000, was not renewed by the
11 Company in 2007.

12 The Company continues to honor its commitment to not actively promote ACE. This is
13 accomplished by excluding the link to ACE on its website and the customer’s bill and having
14 other options promoted through Customer Service Representatives. However, “non-authorized”
15 payment locations, such as ACE, are abundant and offer bill pay as a service to *their own*
16 customers, the ones who choose to do business with them.

17 **E. Additional Bill Assistance.**

18 ACAA has requested that TEP increase its shareholder contribution for low-income
19 customer bill assistance from \$150,000 to \$200,000 per year. The Company has been – and
20 intends to continue – voluntarily funding utility bill assistance programs using shareholder
21 contributions of \$150,000 annually. Its sister company, UNS Electric recently committed to
22 contribute \$50,000 annually for bill assistance. The Company believes these amounts are
23 reasonable and is committing to this funding level for a five-year period, for a total of \$1
24
25

26 ¹⁴⁴ See ACAA Brief at 28-29.

27 ¹⁴⁵ Decision No. 71623 (April 14, 2010) at 64.

¹⁴⁶ Decision No. 71623 (April 14, 2010) at 64.

¹⁴⁷ Decision No. 71623 (April 14, 2010) at 64.

1 million.¹⁴⁸ ACAA agreed at hearing that the Commission cannot order a utility to direct
2 shareholder funds to charitable contributions.¹⁴⁹

3 **F. Environmental Cost Adjustor.**

4 TEP is beset with the ever-increasing costs of complying with environmental mandates. Based on
5 current estimates of environmental compliance costs, the Environmental Cost Adjustor (“ECA”)
6 will not be able to keep up. TEP therefore proposes increasing the cap to 0.5% of annual
7 revenues.¹⁵⁰

8 Staff’s Opening Brief states that it is “opposed” to this change but does not say why.¹⁵¹
9 Staff’s unsupported objection should be rejected.

10 RUCO argues that the “Company has not shown that it has been harmed by the under
11 collection of revenues.”¹⁵² RUCO’s statement is very carefully phrased. While the ECA has not
12 yet hit the cap, TEP’s forecast of environmental costs shows that those costs will exceed the cap.
13 No party has disputed that forecast.

14 RUCO also argues that increasing the cap exposes ratepayers to more risk, and that the
15 ROE has not been adjusted for that risk.¹⁵³ But the risk is really caused by the environmental
16 mandates driving these costs up—ratepayers will bear those costs either in the ECA or in the next
17 rate case. The ECA smooths that out, thus reducing the ratepayer’s risk in practical terms.
18 Further, TEP’s generation portfolio is likely more exposed to these environmental risks than the
19 average of the sample group used to set the ROE. While TEP is adjusting its generation portfolio
20 as quickly as feasible, generation assets are long-term and TEP has little choice about the
21 environmental costs it bears.

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25 ¹⁴⁸ See Tr. (Zwick) at 639.

26 ¹⁴⁹ See Tr. (Zwick) at 637.

27 ¹⁵⁰ TEP Brief at 54-55.

¹⁵¹ Staff Brief at 33.

¹⁵² RUCO Brief at 21:17-18.

¹⁵³ RUCO Brief at 21:18-20.

1 **XIII. Conclusion.**

2 TEP requests that the Commission approve the relief requested in its Initial Post-Hearing
3 Brief.

4 RESPECTFULLY SUBMITTED this 14th day of November, 2016.

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6
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Attachment A

Tucson Electric Power Company
Summary of Non-fuel Revenue Allocation
Test Year Ended June 30, 2015

Customer Class	Current Adjusted TY Revenue (000's)	TEP (000's)	Staff/RUCO (000's)	*AECC/Noble (000's)
Residential	432,072	51,880	54,501	76,683
SGS	269,039	(3,947)	(10,666)	(8,553)
Med/Large GS	114,102	27,795	29,158	18,278
LPS	134,106	4,245	5,917	3,529
138kV	0	615	1,999	(2,091)
Lighting	4,971	913	591	1,101
Sub Total	954,289	81,501	81,500	88,947
Rider-14 Reserve	-	-	-	(7,471)
Total	954,289			81,476

*AECC revenues reflect their recommendation of the option 1 buy-through proposal